*Environ. Sci. Technol.* **2011,** *45,* 215–222

# Mesoscale Carbon Sequestration Site Screening and CCS Infrastructure Analysis[†]

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*Received May 1, 2010. Revised manuscript received July 16, 2010. Accepted July 22, 2010.*

We explore carbon capture and sequestration (CCS) at the mesoscale, a level of study between regional carbon accounting and highly detailed reservoir models for individual sites. We develop an approach to $CO_2$ sequestration site screening for industries or energy development policies that involves identification of appropriate sequestration basin, analysis of geologic formations, definition of surface sites, design of infrastructure, and analysis of $CO_2$ transport and storage costs. Our case study involves carbon management for potential oil shale development in the Piceance-Uinta Basin, CO and UT. This study uses new capabilities of the *$CO_2$-PENS* model for site screening, including reservoir capacity, injectivity, and cost calculations for simple reservoirs at multiple sites. We couple this with a model of optimized source-sink-network infrastructure (*SimCCS*) to design pipeline networks and minimize CCS cost for a given industry or region. The *$CLEAR_{uff}$* dynamical assessment model calculates the $CO_2$ source term for various oil production levels. Nine sites in a 13,300 km$^2$ area have the capacity to store 6.5 $GtCO_2$, corresponding to shale-oil production of 1.3 Mbbl/day for 50 years (about 1/4 of U.S. crude oil production). Our results highlight the complex, nonlinear relationship between the spatial deployment of CCS infrastructure and the oil-shale production rate.

## 1. Introduction

Carbon Capture and Storage (CCS) through injection of $CO_2$ into deep geologic formations is one of the most promising technologies for mitigation of human-induced climate change (*1*, *2*). Active examples of CCS are limited in both the scale of the injections being performed and the complexity of the facilities involved (*3*). For example, at two of the largest industrial CCS sites (In Salah and Sleipner), $CO_2$ is removed from a gas production stream, separated, and reinjected into geologic formations quite near the gas source region at rates of approximately 1 million metric tons per year ($MtCO_2$/yr) (*4*, *5*). As noted by the U.S. Secretary of Energy, Steven Chu, tackling the climate problem while still utilizing coal and other nontraditional sources of energy (oil shale, tar sands) will require much larger CCS projects to be undertaken (*6*). Because the scale of anthropogenic $CO_2$ emissions is so large (18 billion $tCO_2$/yr), sequestration of this volume could require on the order of 30 km$^3$ per year (correction from ref *6* using subsurface storage density of supercritical $CO_2$ = 600 kg/m$^3$).

The increase in the scale of injection scenarios that will be required to sequester ever increasing volumes of $CO_2$ necessitates a new methodology of systems analysis that moves beyond the primary current paradigm of single injection reservoirs coupled to limited sources (*7*). Currently, analysis of large scale injection systems has been limited to basin-scale reservoir modeling of long-term total injections on the order of 1−10 km$^3$, without infrastructure optimization (*8*, *9*). Analysis of CCS infrastructure (e.g., pipeline networks) has taken into consideration multiple $CO_2$ source and sink locations (*10*), but associated injection calculations have been simplified. On the other end of the scale, recent studies of greenhouse gas (GHG) emissions management have approached the potential solution of CCS by evaluating the regional match between $CO_2$ sources and available gross pore space in geologic formations (e.g. ref *11*). While studies on the broad scale are a necessary first step to bound the problem for policy making and industry planning, the practical challenge of building an integrated and realistic CCS infrastructure system requires more detailed analysis. However, well-characterized sites (e.g., depleted oil reservoirs) and detailed reservoir models may not be available in the vicinity of the $CO_2$ sources of interest. Prior to defining target pore space and developing reservoir models, a mesoscale evaluation of $CO_2$ transport and storage can highlight important information to inform later site-scale studies, such as important reservoir properties and costs.

The process of capturing, transporting, and storing $CO_2$ ultimately requires deciding *where* and what *capacity* infrastructure to construct. These infrastructure decisions include where and how much $CO_2$ to capture, where and what capacity pipelines to build, and where and how much $CO_2$ should be stored. However, almost all regional CCS studies make simplifying assumptions regarding the *location* and *capacity* of CCS infrastructure (*10*); for example, that all sinks in a region have the same injection and storage cost, that sources must capture all produced $CO_2$ regardless of system-wide economics, and that pipelines directly connect $CO_2$ sources to geologic reservoirs. In reality, infrastructure costs and capacities vary considerably across a region and consequently understanding how $CO_2$ should be captured, transported, and stored is a complex decision. For example, aggregating $CO_2$ flows into large trunk-pipelines generates economies of scale that cannot be achieved using direct source-sink pipelines. Also, for instance, using a single cost-value for $CO_2$ storage obfuscates the complex relationship between captured $CO_2$ and spatially varying $CO_2$ storage. Consequently, it is critical to use a spatially explicit approach for modeling how $CO_2$ is captured, transported, and stored and to understand and quantify the impact of *space* on CCS costs and feasibility.

In this paper we explore the mesoscale CCS analysis that lies between regional carbon accounting and highly detailed reservoir models for individual sites. We describe an approach to $CO_2$ sequestration site screening for industries or energy development policies that involves identification of ap-

[†] This manuscript is part of the Environmental Policy: Past, Present, and Future Special Issue.

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10.1021/es101470m 
Published on Web 08/10/2010

propriate sequestration basin, analysis of sequestration target formations, surface site definition, infrastructure design, and analysis of costs for $CO_2$ transport and storage. This approach uses new *$CO_2$-PENS* (Predicting Engineered Natural Systems) model capabilities for site screening, including capacity, injectivity, and cost calculations for simple reservoirs at multiple sites (*7, 12*). The site screening capability is integrated with a model of optimized source-sink-network infrastructure (*SimCCS*—Scalable infrastructure model for Carbon Capture and Storage) to design pipeline networks and minimize costs of CCS for a given industry or region.

## 2. Overview of Oil Shale Case Study

Our case study for exploring the mesoscale CCS analysis addresses substantial new power production required and the associated carbon management to support transportation fuel security through potential oil shale development in the western U.S. Reserves of oil shale in the Rocky Mountain region have been estimated at 1.8 trillion bbl (*13*); in comparison, the proven oil reserves in Saudi Arabia are estimated at only 0.26 trillion barrels (*14*). These resources are under increased scrutiny as global consumption and prices of oil increase, and projections of future energy demand in the U.S. may require the use of heavy or unconventional hydrocarbon resources (*11, 15*). Furthermore, the Task Force on Strategic Unconventional Fuels (including members from DOE, DOD, and several Western states) defined a target for Green River Formation oil shale production of 2.5 million barrels of oil per day (bbl/day) by the year 2035 (*16*), about half of current domestic crude oil production (*17*). Recent law briefly prohibited federal agencies from procuring fuels derived from unconventional sources unless the lifecycle greenhouse gas (GHG) emissions of that fuel are less than or equal to those associated with conventional fuels (*18*). As regulations over everything from land use, to water rights, to air quality are debated among all stakeholders, industrial interests have made progress in developing and deploying novel technologies for in situ resource production at the field demonstration scale. These new methods seek to convert the oil shale (actually a kerogen-rich marl stone) to a refinable crude via subsurface heating. One of the leading potential production processes that has emerged in the literature, Shell's in situ conversion process (ICP), requires gigawatts of electrical power for the in situ retort process, primarily for the down-hole heaters (*19*). Carbon dioxide ($CO_2$) emitted during electricity generation and retort gas cleanup must be managed in order to mitigate this excess carbon intensity of the resulting fuel. Given the magnitude of the resources involved in large-scale oil-shale production, carbon management is best analyzed at the basin scale, addressing the interdependency of energy, water, and carbon. Whereas the oil-shale to fuel production process provides a good demonstration for basin-wide carbon management, the issues are directly relevant to other regional power production concerns, including modifications or replacements of existing power production facilities.

The feasibility of oil shale development is based in part on the costs associated with mitigation of GHG emissions, which scale with the fuel production rate. The U.S. Geological Survey estimates an oil shale resource in place in the Green River formation of about 1.5 trillion barrels in the Piceance Basin, Colorado, alone (*20*). Farrell and Brandt (*15*) suggest that CCS could reduce total emissions from the production of oil shale-derived transportation fuels by 50%, primarily by mitigating the electricity-generation emissions. CCS costs lie primarily in capturing, transporting, and injecting $CO_2$ into subsurface geologic reservoirs. In addition, the injection of $CO_2$ may require treatment of a nearly equivalent volume of produced saline water and disposal of nontreatable water (*9*).

In this study we assume that the copious electricity required for industry scale shale oil production in the Piceance Basin would be generated by new power plants utilizing efficient natural gas combined cycle (NGCC) or integrated gasification combined cycle (IGCC) power plants and their associated capture efficiencies and costs (*21*). Captured $CO_2$ emissions from oil shale development are assumed to be transported via pipelines to geologic sequestration sites in saline aquifers in the region.

## 3. Approach for Screening Sequestration Sites and Infrastructure

Geologic sequestration of $CO_2$ requires the availability of sufficient storage capacity while at the same time ensuring that natural barriers prevent the potential migration of the injected fluid. In geologic terms, this translates to deeply buried porous, permeable rock which will accept and hold large amounts of $CO_2$ and which is bounded by low-permeability confining layers to prevent $CO_2$ escape into the accessible environment. As such, the primary criteria for selecting geologic sequestration targets include 1) capacity and injectivity parameters such as porosity, permeability, thickness, and spatial extent of formation; 2) physical trapping mechanisms such as low-permeability caprock and structural confinement (e.g., fold or dome); 3) depth range conducive to pressure and temperature conditions supporting supercritical $CO_2$ and feasible for drilling and injection; 4) proximity to $CO_2$ source; 5) accessibility of land surface and pore space; and 6) safety and risk considerations and public acceptance (*22, 23*).

Bachu (*22*) identifies 15 criteria for screening and ranking sedimentary basins at the continental scale in terms of suitability for carbon sequestration, ranging from tectonic setting through geothermal conditions to infrastructure. Once a particular $CO_2$ source has been identified, the site screening process to meet the conditions above can be simplified to

1. identification of a sequestration basin in reasonable proximity to the emissions sources.
2. selection of potential sequestration target formations (saline formations, depleted oil and gas reservoirs, coal beds, etc.).
3. land-access screening.
4. analysis of reservoir capacity and injectivity at one or more sites.
5. infrastructure analysis.
6. assessment of safety and risk, including feasibility of monitoring, verification, and accounting (MVA) of $CO_2$ leakage.

Cost is an important variable in each of these steps.

## 4. Description of Models

We evaluate the feasibility of managing $CO_2$ emissions from oil shale development activities in Colorado's Piceance Basin using models of geologic sequestration (*$CO_2$-PENS*), infrastructure design (*SimCCS*), and $CO_2$ production rate from oil shale development activities (*$CLEAR_{uff}$*). Risk assessment with *$CO_2$-PENS* as described by Stauffer and others (*7*) is not part of this study. Additional information on these models is included in the Supporting Information.

*$CO_2$-PENS* is a hybrid system model for performance and risk assessment of geologic sequestration of $CO_2$ (*7, 12*). The model is designed to perform probabilistic simulations of $CO_2$ capture, transport, injection, and migration in geologic reservoirs and to calculate associated costs. The latest version of *$CO_2$-PENS* used in this study includes explicit spatial data such as topography on the reservoir/cap-rock interface, evolution of saturation and pressure during injection, and dip on overlying aquifers that may be impacted by leakage upward through wellbores and faults. The inclusion of spatial

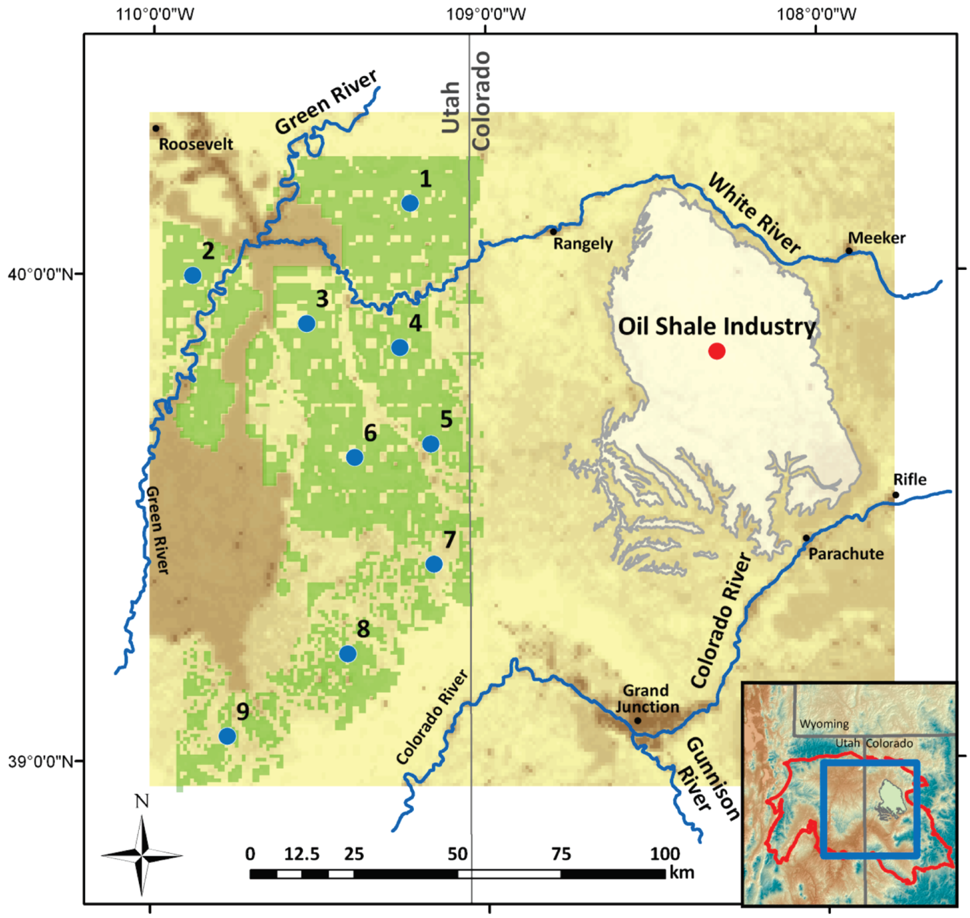


**FIGURE 1. Location of the oil shale carbon management study area in northwestern Colorado and northeastern Utah. The $CO_2$ sequestration site access mask (green patchwork) is shown in eastern Uinta Basin, Utah, relative to the oil shale resource in the Piceance Basin. The nine sequestration sites are shown by the numbered blue circles, and the presumed $CO_2$ source is shown by the red circle in the center of the Piceance Basin. The inset map indicates the location of the study area in Utah and Colorado. The irregular red boundary indicates the extent of the Uinta-Piceance Basins. The blue square denotes the extent of the main map.**

awareness in risk analysis is becoming increasingly necessary for problems such as $CO_2$ sequestration and long-term storage of nuclear waste at DOE controlled facilities.

*SimCCS* is an economic-engineering optimization model developed by Middleton and Bielicki (*10*). *SimCCS* spatially deploys CCS infrastructure ($CO_2$ sources, pipelines, and sinks) using a combination of infrastructure costs (economics) and infrastructure capacities (engineering). *SimCCS* is a spatially explicit model: $CO_2$ sources and sinks are connected via a capacitated network of pipelines and individual pipeline routes that are designed to avoid geographically costly areas. Given a target amount of $CO_2$ to capture in a region, *SimCCS* optimally selects (i) which sources should capture $CO_2$ and (ii) what amount; (iii) which geologic reservoirs should store $CO_2$ and (iv) how much; (v) where dedicated $CO_2$ pipelines should be constructed and (vi) at what capacity; and (vii) how to optimally allocate $CO_2$ among the optimal set of sources and sinks.

*CLEAR$_{uff}$* (CLimate-Energy Assessment for Resiliency applied to Unconventional Fossil Fuels) is a dynamical assessment model that uses an integrated framework to simulate the oil shale production process; demands for electricity, water, and labor; GHG emissions; and economics (*24*). *CLEAR$_{uff}$* calculates the total $CO_2$ emissions as the sum of the contributions from electricity generation and cleanup of the NG coproduced during the in situ retort process (ICP).

In this study we focus on two of the scenarios for electricity generation in the *CLEAR$_{uff}$* model: (1) 100% natural gas combined cycle (NGCC) power plants, both for on-site and off-site power production, and (2) NGCC for onsite power production combined with offsite coal combustion in an integrated gasification combined cycle (IGCC) power plant (e.g. ref *11*). Both of these scenarios incorporate advanced thermo-electric generation technologies that are capable of integral $CO_2$ capture and both consider power production within the basin of study. The largest proportion of $CO_2$ emissions originates in the production of electricity for the ICP heating process; for example, in our first scenario approximately 86% of the emissions result from electricity generation by NGCC and about 14% of the emissions result from stripping $CO_2$ from retort gases. Costs for the capture process are included in *CLEAR$_{uff}$*, in terms of capital costs and electricity and water demand. Captured $CO_2$ emissions from oil shale development are assumed to be transported via pipelines to geologic sequestration sites in saline aquifers in the region.

## 5. Example

**5.1. Site-Screening Considerations.** We developed a set of potential geologic sequestration sites to place $CO_2$ emissions from the hypothetical Piceance Basin oil shale industry, based on the screening approach described in Section 3. Considering information from previous $CO_2$ sequestration modeling studies and assessments of oil, gas, and oil shale resources, we chose the eastern Uinta Basin (Figure 1) for our sequestration area, and we chose the Entrada and Castlegate Sandstones as target formations (details of these choices are presented in the Supporting Information).

In addition to geological considerations (suitable stratigraphy and structure), the selection of potential $CO_2$ seques-

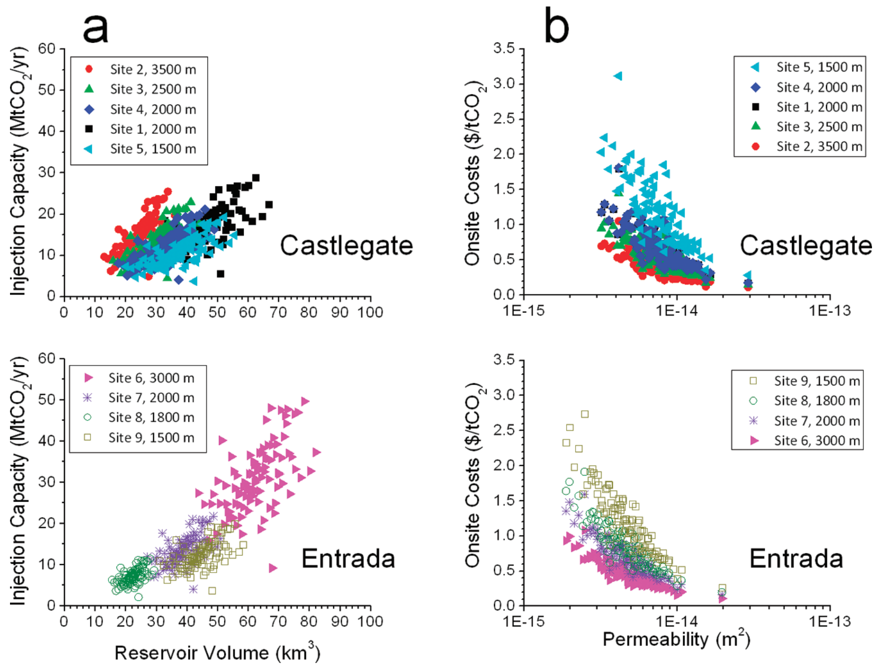


**FIGURE 2. a) Plot of reservoir capacity vs reservoir volume for the Entrada and Castlegate sites at various reservoir depths. Point clouds represent 100 *$CO_2$-PENS* realizations for each site, sampling distributions for multiple input parameters. The areas of most of the Castlegate sites (top) are similar (ca. 500 to 750 km$^2$), as reflected in the consistent range of injection capacity (4 to 25 $MtCO_2$/yr) for each site. The reservoir volume required to sequester a given amount of $CO_2$ decreases with increasing reservoir depth. The areas of the Entrada sites decrease in sites 6, 7, and 8 (812, 504, and 289 km$^2$, respectively), and their point clouds define a smooth arc of increasing injection capacity with increasing volume as depth increases. b) Plot of total on-site cost vs permeability for the Entrada and Castlegate sites at various reservoir depths. Sites at greater depth require fewer wells to inject a given mass of $CO_2$ and therefore incur lower total storage costs.**

tration sites is based on logistics and access to the target reservoir. The legal aspects of access to "pore space" relative to surface and mineral rights are currently being legislated in several U.S. states (e.g., Montana Senate Bill 498, 2009), and the complexities of site selection on this basis are not considered in this study. Instead, we use land access as a proxy for reservoir access (consistent with Montana law) to demonstrate some of the important considerations involved in defining the extent of potential injection sites within a broad region.

Nine sites are defined within a 13,300 km$^2$ area in the eastern Uinta Basin by building a filter for land surface layers in a geographical information system (GIS). The land screening process is built on rasters that describe the slope, land cover, land ownership, and water bodies (Supporting Information, Figure S-1). This process eliminates urban areas, riparian areas, and wetlands and a 2-km surrounding buffer; slopes greater than five degrees that would make drill pad development difficult; all land ownership except Bureau of Land Management; and areas underlain by Entrada and Castlegate sandstones above and below the target depth (1 to 4 km). About 80% of the land in the Uinta and Piceance Basins is managed by the federal government (*25*). Private land could provide additional injection opportunities, but it is not considered in this analysis because of the difficulty in developing a general screening criterion. The resultant geographic mask (Figure 1) presents a pattern of land access that divides the region into several large areas that are separated by the canyons of the Green and White rivers. The nine sites (Figure 1) vary by area (289−900 km$^2$), target formation (Castlegate or Entrada sandstone), depth to the top of the reservoir (average 1500 to 3500 m), and distance from the presumed $CO_2$ source in the center of the Piceance Basin.

**5.2. $CO_2$ Sequestration Analysis.** *Approach.* In this study we ran two sets of *$CO_2$-PENS* realizations for each site in order 1) to calculate the total capacity ($MtCO_2$) and the annual injection capacity ($MtCO_2$/yr) of each site, defined as an administrative unit within the reservoir, and 2) to calculate the number of wells and length of distribution piping required to completely fill the reservoir within 50 years, without exceeding the unit boundaries. Annual injection capacity is calculated by dividing the total reservoir capacity by the injection period (50 yr). Constant reservoir permeability, porosity, and thickness values are assumed for each reservoir, but the parameter values for each model realization are sampled from probability distributions (Table S-2). Total on-site costs are calculated for the 'full' reservoir unit based on this second round of model runs. The cost and design of regional $CO_2$ pipelines are calculated by *SimCCS* in a separate analysis step using results from *$CO_2$-PENS*. The Supporting Information contains descriptions of the calculation of reservoir porosity, permeability, initial pressure and temperature, and costs.

Uncertainty in reservoir and cost input parameters is quantified in *$CO_2$-PENS* using the Monte Carlo method by running many realizations of a site model and returning statistical representations of the output parameters. We ran 100 *$CO_2$-PENS* realizations of each site; linear regression slopes through the volume-capacity points for each site change by about 11% when 500 realizations were sampled. Values for input parameters are sampled from distributions using a Latin Hypercube Sampling method that ensures that the uncertainty of the entire parameter space is sampled in the course of the set of model realizations.

**$CO_2$-PENS Results.** The combined mean capacity of the nine sequestration sites is 6.5 $GtCO_2$ or about 131 $MtCO_2$/yr over 50 years (Supporting Information, Table S-3). Reservoir capacity and annual injection capacity are most strongly controlled by variations in porosity and reservoir thickness (Figure 2a). In order to compare injectivity values among sites of different areas, the reservoir volume is calculated for each realization by multiplying the site area by the reservoir thickness sampled for each model realization. The point

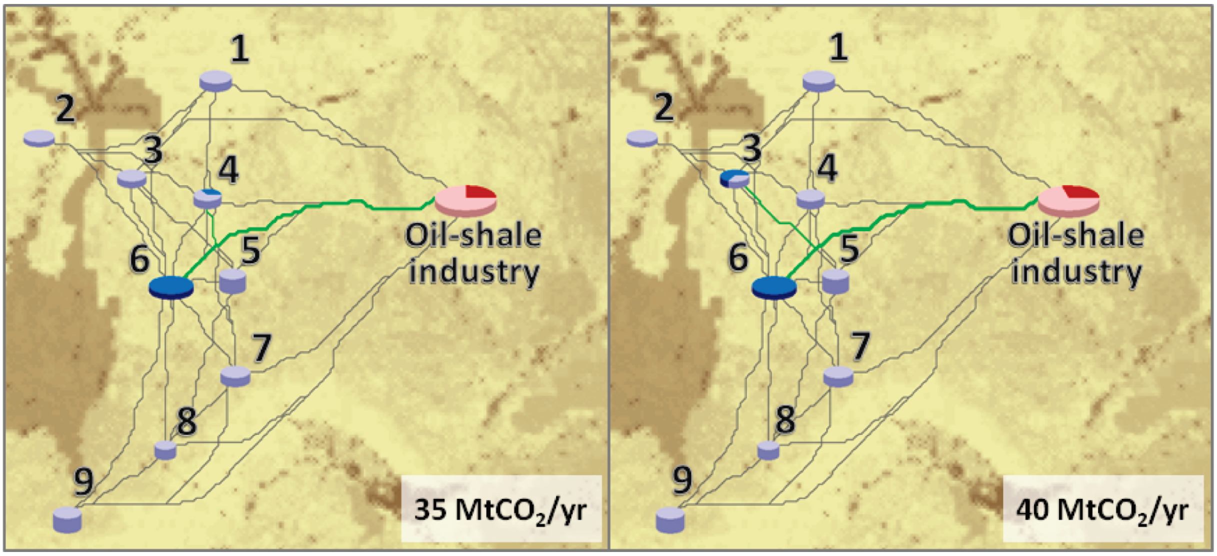


**FIGURE 3. Spatial infrastructure deployment for capturing, transporting, and storing 35 and 40MtCO$_2$/yr. These CO$_2$ rates equate to oil-shale production of 0.55 and 0.63 million bbl/day (Scenario 1) and 0.36 and 0.41 million bbl/day (Scenario 2). The 2D area of the blue cylinders (sinks) is proportional to annual sink capacity, the height is proportional to the variable storage cost, and the blue wedges represent the amount of CO$_2$ injected and stored. The 2D area of the red cylinder (CO$_2$ source) is proportional to total possible CO$_2$ production (1.35 million bbl/day) and production for the chosen scenarios. The uniwidth gray lines illustrate the candidate pipeline routes. Green lines illustrate where the pipeline network was constructed for each scenario; line width is proportional to the pipeline capacity deployed. The cost surface ranges from low costs (yellow) through to high costs (brown).**

clouds representing 100 *CO$_2$-PENS* realizations for each site in volume-capacity space are shown in Figure 2. With increasing depth, the reservoir volume required to sequester a given mass of $CO_2$ decreases, as a result of the variations in water and $CO_2$ phase mobilities that favor flow of supercritical $CO_2$ with increasing pressure and temperature (*7*).

Total on-site cost is most sensitive to permeability, and the steepness of the slope of that relationship varies inversely with depth at a given site (Figure 2b). The primary contributor to on-site costs is drilling new injector wells (ca. 94%), with on-site distribution piping and on-site maintenance over the first 50 years contributing far less (3% each). This primary effect of drilling cost can be seen in the vertical stacking of on-site costs by depth among the examples sites (Figure 2b). For a given formation, a deeper reservoir is actually cheaper to utilize than a shallower reservoir, as noted by Stauffer and others (*7*).

**5.3. Infrastructure Considerations.**

**Approach.** Previous studies involving *SimCCS* (*10, 26, 27*) used a weighted-cost surface developed by MIT (*28*). The MIT surface was generated by assigning an individual weight to geographical features (such as national/state parks and urban areas) and summing these weights for each 1 km by 1 km grid cell. The cost to construct a pipeline across a grid cell was derived by multiplying the cell-weight by the engineering construction cost for a 1 km pipeline (capacity dependent) using natural gas pipelines as an analogue. The MIT approach has several distinct shortcomings: engineering costs should not vary with all underlying geography (e.g., federal/state parks), right-of-way (ROW) and engineering costs are not separated, and the cost surface produces excessively large construction costs.

In this study, we generate a new approach to developing a weighted-cost surface. First, the cost surface is based on much more refined (spatially and contextually) geographical inputs: land use (e.g., cropland, forest, lakes), land ownership (e.g., federal, Indian, private), population *density*, and topography. Topography and population inputs themselves are more sophisticated. For example, a change of slope can increase construction costs while aspect may lower (pipeline running parallel to slope) or increase (down/upslope) costs. And the impact of urban areas is no longer a Boolean decision; instead costs are broadly proportional to population density. Second, construction and ROW costs are derived separately. For example, topography impacts construction costs but not ROW, whereas land use may reduce (e.g., pastureland, scrubland) or increase (e.g., wetlands, forests) construction costs. As a result, *SimCCS* combines and balances—ROW costs are almost invariable to pipeline capacity, whereas construction costs are highly dependent—two separate cost surfaces. Finally, in this study, we use a cost surface based on 800 m grid cells (see Figure 1). The cost surface ranges from brown (grid cells representing areas with, on average, high combined ROW and construction costs) to yellow (lower costs).

**SimCCS Results.** The amount of $CO_2$ generated and captured by the oil-shale industry is proportional to the fuel production rate. The *CLEAR$_{uff}$* model calculates that a single oil-shale company producing 0.1 million bbl/day (36.5 million bbl/year) would capture between 6 MtCO$_2$/yr (Scenario 1: using 100% NG in an NGCC power plant) and 10 MtCO$_2$/yr (Scenario 2: combination of NGCC and IGCC power plants) once the maximum fuel production level is reached. A group of companies producing 0.5 million bbl/day within the Piceance Basin would capture between 32 and 47 MtCO$_2$/yr. Extensive oil-shale development producing 1.3 million bbl/day, approximately one-quarter of current domestic crude oil production (*17*), would require CCS infrastructure for between 83 and 127 MtCO$_2$/yr; the latter is approaching the total capacity of the nine sinks identified in this study (131 MtCO$_2$/yr over 50 years) but certainly not the total capacity of the Uinta Basin. Additional information on the *CLEAR$_{uff}$* calculation of the $CO_2$ source term is included in the Supporting Information.

There is a complex and nonlinear relationship between the spatial deployment of CCS infrastructure (transport and inject/store $CO_2$) and the oil-shale production rate. Figure 3 illustrates the spatial infrastructure required to transport and store 35 and 40 MtCO$_2$/yr. *SimCCS* optimally constructs a 30″ pipeline (35.13 MtCO$_2$/yr capacity) between the oil-shale industry and sink #6, and a 16″ pipeline (6.86 MtCO$_2$/yr capacity) spur from this trunkline to sink #4; 31 MtCO$_2$/yr is delivered to sink #6 (31 MtCO$_2$/yr capacity) and 4 MtCO$_2$/

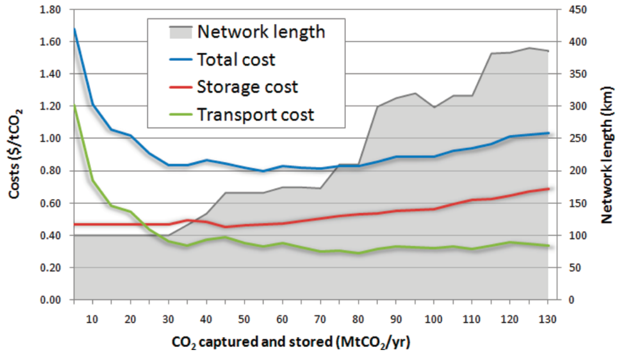


**FIGURE 4. $CO_2$ transport and storage infrastructure costs (primary *y*-axis) and network length (secondary *y*-axis). Costs are represented by lines: green ($CO_2$ transportation cost), red (injection and storage cost), and blue (total transport and storage infrastructure costs). The network length is represented by the gray line.**

yr to sink #4 (11.98 $MtCO_2$/yr capacity). Sink #6 is both the largest and cheapest of the nine sinks, is solely used for ≤30 $MtCO_2$/yr scenarios, and is utilized to capacity for all ≥30 $MtCO_2$/yr scenarios. Although sink #5 is closer to the oil-shale industry than the sinks #4 and #6, the cost savings of a shorter pipeline are outweighed by sink #5's high cost (cylinder height in Figure 3) related to the reservoir's shallow depth. Moreover, sink #4 is utilized even though sinks #1−3 are cheaper; in this case, savings achieved from lower cost sinks are overwhelmed by the extra pipeline costs.

Increasing the amount of managed $CO_2$ to 40 $MtCO_2$/yr impacts pipeline capacities, pipeline routes, and which sinks are utilized (Figure 3). A 36″ pipeline (56.36 $MtCO_2$/yr capacity) is now required to transport the 40 $MtCO_2$/yr produced at the single source. A 30″ pipeline is still optimally deployed to completely fill sink #6, but now the single spur is a 20″ pipeline (12.26 $MtCO_2$/yr capacity) delivering 9 $MtCO_2$/yr to sink #3 (13 $MtCO_2$/yr capacity). Sink #4 is no longer used even though it has enough capacity to store the 9 $MtCO_2$/yr that cannot be stored in sink #6. Essentially, the economies of scale achieved by transporting 9 $MtCO_2$/yr in a 20″ pipeline make it possible to use the more distant, cheaper sink #3.

The relationship of infrastructure costs and network length with $CO_2$ management scenarios is also complex and nonlinear (Figure 4). Management of the first 5 $MtCO_2$/yr costs $1.68 $tCO_2$/yr, quickly dropping to $0.80 $tCO_2$/yr at 55 $MtCO_2$/yr, and then gradually rising to $1.03 $tCO_2$/yr by 130 $MtCO_2$/yr. Storage costs start at $0.47 $tCO_2$/yr and almost continually rise to an average of $0.69 $tCO_2$/yr. Transport costs peak at $1.21 $tCO_2$/yr (5 $MtCO_2$/yr), falling as low as $0.29 $tCO_2$/yr (55 $MtCO_2$/yr)-though generally averaging around $0.35 $tCO_2$/yr. For ≤30 $MtCO_2$/yr scenarios, a single 100 km pipeline connects the oil-shale industry with sink #6; although the pipeline route does not change, the pipeline diameter varies between 16″ (6.86 $MtCO_2$/yr) and 30″ (35.13 $MtCO_2$/yr). Because only sink #6 is utilized (≤30 $MtCO_2$/yr), the storage costs ($0.47 $tCO_2$/yr) are identical. Beyond 30 $MtCO_2$/yr, *SimCCS* is predominantly forced to select more expensive sinks, though total transport and storage costs remain flat from 30 to 80 $MtCO_2$/yr ($0.81 to $0.85 $tCO_2$/yr) due to increasing economies of scale in the pipeline network. Above 80 $MtCO_2$/yr, the pipeline network can no longer continue to reduce transportation costs with increasing $CO_2$; therefore, total transport and storage costs begin to rise as *SimCCS* uses the more expensive sinks.

## 6. Discussion

The evaluation of carbon management options for potential new industries requires a shift from theoretical considerations of aggregate regional $CO_2$ emissions and pore-space capacity to consideration of specific sequestration sites and local transport infrastructure. At that scale, one must consider the details of injection formations, land surface and pore space access, pipeline routing, environmental regulations, risk and safety, and costs. The mesoscale evaluation of $CO_2$ transport and storage focuses on infrastructure configurations at the level of the basin that contains the emissions sources. The combination of *$CO_2$-PENS* and *SimCSS* provides a quantitative assessment of important parameters in sequestration site selection and pipeline network design. The statistical approach considers uncertainty in the characterization of storage reservoirs and produces variable infrastructure costs and network connectivity.

Storage capacity for as much as 33 $GtCO_2$ may exist within the pores of permeable formations within 50 miles of the Uinta-Piceance Basins, and nearly half of this capacity may be available within the actual basins (*11*). Storage targets include saline formations (90% of capacity), unmineable coal seams, and depleted oil and gas reservoirs. In the present study, we analyze the capacity and costs for injection of $CO_2$ into saline formations at nine hypothetical sites in the Uinta basin. Our example sites have a combined mean capacity of about 6.5 $GtCO_2$, or 131 $MtCO_2$/yr over 50 years of injection. This calculated total capacity is about one-fifth of the in-basin capacity as assessed by Dooley and others (*11*).

The aggregate capacity of the study sites (131 $MtCO_2$/yr) can store the total captured $CO_2$ from power production using 100% NGCC and retort natural gas cleanup for shale oil production rates up to about 2 million bbl/day and using a combination of NGCC and IGCC up to 1.3 million bbl/day. The full shale oil production rate for the Green River Formation in Utah, Colorado, and Wyoming has been estimated at 2.5 to 3 million bbl/day (*11, 25*). This production rate would require up to twice as much $CO_2$ sequestration capacity as was modeled in this study, depending on the technology used to generate the necessary electricity. Taking into consideration that technical, regulatory, and societal limitations will reduce the amount of $CO_2$ that can realistically be stored in the basins (e.g. ref *11*), we conclude that, by simply scaling the capacities modeled in this study to the geologic formations at basin scale, the Uinta and Piceance Basins would provide the capacity necessary to store the $CO_2$ emissions from the full output of the oil shale industry in the region. However, mesoscale studies of potential sequestration sites in adjoining areas (e.g., the Green River Basin) would be necessary for evaluating the potential for managing $CO_2$ emissions from development of the entire Green River Formation oil shale.

There is a complex, nonlinear relationship between the spatial deployment of CCS infrastructure and the oil-shale production rate. The interplay among pipeline size (capacity), sink capacity and cost, and sink location relative to the source produce nonintuitive variations in the network topology and cost as the oil production (and $CO_2$ source rate) increase. The placement of pipeline trunklines and spurs to sinks balances optimal pipeline length and pipe size with the capacity, cost, and proximity of available sinks. Although a sink may be closer to the oil-shale industry than the others, the cost savings of a shorter pipeline may be outweighed by the sink's high cost. Conversely, the economies of scale achieved by transporting large amounts of $CO_2$ in a large pipeline may make it possible to use more distant, cheaper sinks.

As the CCS infrastructure increases in size, economies of scale are realized. Pipeline diameter is strongly anticorrelated with cost, especially among small pipe sizes, leading to a steep initial decline in transport costs as the CCS capacity ramps up. Storage capacity and costs may be relatively constant during the initial phases of CCS development if the capacity of the first storage site is sufficiently large. The combination of the cost curves for $CO_2$ transport and storage may result in a window of minimum costs for a particular range in size of the CCS program: in this study, transport and storage of 30 to 80 $MtCO_2$/yr resulted in the most cost-effective program size.

Apart from EOR projects, existing CCS projects typically link a single $CO_2$ source to a single reservoir using a single pipeline. As a result, cost estimates and reports in the literature for capturing, transporting, and storing $CO_2$ tend to a summation of these individual costs. These summations fail to take into account savings through economies of scale or extended expenses such as a large CCS system being forced to use more expensive storage reservoirs (as opposed to the a single, cheapest reservoir). Regardless, the CCS infrastructure costs for the Piceance basin oil-shale industry calculated by *SimCCS* fall approximately in the middle of the range of previously published estimates. For example, the IPCC (*29*) report estimates U.S. onshore injection and storage in a saline aquifer between \$0.4/$tCO_2$ and \$4.5/$tCO_2$, with a representative value of \$0.5/$tCO_2$.

Uncertainties in reservoir properties (e.g., permeability, thickness, porosity) as well as reservoir heterogeneity will strongly affect the injectivity, capacity, and costs associated with any potential sequestration reservoir. We used constant representative values for reservoir properties in this analysis, and the resulting infrastructure analysis illustrates the basic variability in utilizing various combinations of storage sites. A next step is to investigate the effect of uncertainty in reservoir characteristics on the infrastructure costs and design. An outcome will be the choice of optimal transport and storage configuration in the face of uncertainty.

In contrast to depleted oil and gas reservoirs, the use of saline formations for $CO_2$ sequestration provides the opportunity to use new formations in undeveloped regions. However, the patchwork of land ownership and variable land use means that access to pore space may not be easy. We screen for land access as a proxy for pore space access, highlighting opportunities and limitations for defining individual injection sites. Although the legal aspects of pore-space ownership, as distinct from mineral rights and surface rights, are being defined at the level of state governments (and could result in a highly variable legal landscape), early movers such as Montana are linking the pore space estate to the surface estate.

While not considered in this report, it will be important to consider risk due to $CO_2$ leakage from the reservoir via multiple pathways (e.g., wells and faults) as part of site selection. Monitoring, verification, and accounting (MVA) feasibility and costs will also factor into site screening and decisions about development of particular locations for carbon sequestration. Rules are currently in development at the state and federal levels for regulating MVA, and this study does not explicitly include consideration of MVA technologies, deployment, or costs. Future work will utilize the risk assessment capabilities of *$CO_2$-PENS* to add additional site screening criteria and input to the cost calculations and *SimCCS* infrastructure design optimization (e.g., risk and MVA).

Issues surrounding "produced water" (saline water removed from the formation as $CO_2$ is injected) will also be important for calculating costs and feasibility of CCS projects. While produced water is not explicitly considered in this study, it is evident that, on an equivalent volume basis, the injection of several Mt of $CO_2$ will displace a significant mass of saline water or brine from the formation.

For the oil shale industry or any new emissions sources that require carbon management, the mesoscale CCS evaluation will be followed by site-scale studies involving detailed reservoir characterization, assessment of injectivity and storage capacity, identification of potential leakage pathways, and risk assessment. For so-called green-field areas and undeveloped geologic formations, the mesoscale evaluation provides a cost-effective means to develop important information on capacity, cost, and infrastructure design for these later site-scale studies.


## Acknowledgments

The study of carbon management for oil shale production in the Piceance Basin was performed as part of a larger feasibility study of oil shale development within environmental constraints funded by the DOE Office of Naval Petroleum and Oil Shale Reserves. We are grateful to James Killen, our project manager in DOE-FE, for his valuable insight and support. Development of the injectivity and capacity modules of the *$CO_2$-PENS* model was funded by DOE Office of Fossil Energy through the NETL Carbon Program. We thank Rick Kelley for GIS analysis. Three anonymous reviewers contributed to the clarity of presentation.


## Supporting Information Available

Supporting Information associated with this paper contains additional technical details on geologic site screening, sequestration reservoir properties, functionality and use of the *$CO_2$-PENS*, *SimCCS*, and *$CLEAR_{uff}$* models, and the oil shale case study. This material is available free of charge via the Internet at http://pubs.acs.org.

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ES101470M